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Application Of Inflatable Packers For Production Testing And Conformance Problems In Algeria

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Abstract

Through tubing inflatable packers conveyed with coiled tubing have proved to be ideally suited for multiple zones stimulation, water and/or gas control intervention where accurate fluid placement is essential for the success of the job. The high expansion ratio and sealing capabilities of modern elastomers used today in through tubing Inflatable have allowed operations in more hostile wells than previously possible, increasing job reliability.

Conformance problems related to non desired water and/or gas production is drastically affecting the oil production of certain fields in Algeria. The exclusion of this water and/or gas represents a challenging task by itself. Even more under the hostility of multiple zones intervals open for simultaneous production, making the problem diagnosis a key factor for the success of the intervention.

This paper presents the successful application of a methodology to diagnose and effectively exclude the non desired production with a novel technique using through tubing inflatable packers. A thorough discussion about the inflatable packers, deployment, inflation procedures, zone isolation and selective placement is presented. In addition, four case studies corresponding to the application of this methodology are discussed in detail. Two corresponding to exclusion of water and gas production, respectively, by selective placement of a x-link rigid polymer gel and two corresponding to production testing of isolated intervals.

Finally, results of these interventions are presented. Including stabilized production before and after each treatment.

Introduction

Most of the fields in Algeria produce from sandstone reservoirs where multiple layers are opened to production. The layers might have very different petrographic characteristics and are often well separated by shale beds. Completion of the wells varies from open holes, cemented and perforated liner to slotted liners. Production started in some areas as early as 1959. The pressure decline associated with the production led to establish a pressure maintenance strategy in maturing fields either by gas or water injection[1]. The drawback of this pressure maintenance is that it induces conformance problems such as gas breakthrough or excessive water production. Sophisticated techniques such as water cut diagnostic plots analysis[2], oxygen activated logs or PLT have given the engineer excellent tools to understand the mechanism of the unwanted production. However these methods might not be available or suited in some case and a simple production test of selected layers using inflatable tool might provide sufficient information for the engineer to decide for the appropriate treatment. Moreover, conveying inflatable tool on coiled tubing provides a efficient and accurate way to cure the unwanted production.

In the first part of this paper, the various inflatable tools and their application in analyzing and solving conformance problems will be discussed. Procedures and limitations of the tools will be described. Then in a second part four case studies corresponding to Algerian fields are discussed detailing job design, execution and outcome. It presents conclusions derived from several treatments performed to date and formulates recommendation for future interventions.

Selective treatment and inflatable tools Applications

When a well produces from multiple intervals, both production testing and solving conformance problems usually requires zonal isolation, this allows to selectively evaluate or treat the layer(s) of interest. Because the internal diameter (ID) at the producing depth (cased or open hole) is larger than the ID of the production tubing, the tool is limited by the smaller ID but, at the same time, must conform to the larger ID of the casing for placement. Coiled Tubing (CT) conveyed inflatable tools are the most common way to achieve this requirement.

The years 1993-1996 were the learning curve, as the first generation tools and procedures were applied with mixed success. However, the inflatable tool technology has evolved to the point where CT conveyed Through Tubing (TT) tools have become an established alternative for optimum well intervention. The experience has led to distinguish typical applications were selective placement with Through Tubing tools is the preferred option. These include:

- Selective gas shut-off operations,
- Selective water shut-off operations,
- Selective zonal evaluation,
- Selective acid treatments.

To achieve selective treatments, several inflatable tools are available from the industry:

- Through Tubing (inflatable) Retrievable Bridge Plug (TTRBP)
- Through Tubing (inflatable) Retrievable Packer (TTRP)
- Through Tubing (inflatable) Retrievable Cement Retainer (TTCR)
- Inflatable Straddle Packer.

Multiple setting is an option for straddle packers and TT Packers.

The need for zonal isolation could have multiple origins depending on the application. The two considered here are described hereafter.

Temporary zonal isolation for testing and evaluation

Inflatable tools can be run to isolate a zone for evaluation of a potential treatment. This zone, once isolated, open opportunities for testing the well from an injectivity and production point of view. The well can either be flowed and production tested, or submitted to an injection step rate test.
The result of these tests enables the engineer to make the right decision for intervention. In the case of a well where it is felt that the bottom zone is affecting the production, and should be isolated from the others, the owner of the well can assess the effect of the shut-off before actually permanently abandoning the interval. A TTRBP is set with CT above the undesirable zone and production benefit is evaluated. If of interest the decision can be made to leave the bridge plug in the hole for a longer term or to retrieved the TTRBP and shut off the zone with a chemical treatment, for instance. In this case the RBP is left in hole, and a protective sand plug is placed on the fishing neck. Otherwise, if it appears that isolating the lower zone is not the solution to the well's problem, the TTRBP is retrieved and other options are considered.

The increasing numbers of open hole horizontal wells drilled in Algeria called also for the use of CT conveyed single and multi-set inflatable packers to diagnose unwanted production. This is typically the case in oil producers where the drain intercepted a fissure that connects to the gas or water zone that impart production, the GOR being too high for surface equipment capacity or the water cut being too high for the well to flow. In order to help locate the water or gas entry points without having to run a Coiled Tubing conveyed PLT string, an inflatable tool is ran in the drain. Educated guess based for example on the drilling report (loss zones) help selecting the appropriate setting depth of the packer. The tool is inflated and the portion of the drain above the packer is flown and production evaluated (if a nitrogen lift is required a circulation valve is opened above the element). The new water or gas production is monitored and a decision to treat or to try another setting depth can be made.

Permanent shut-off operation

This is a case were isolation is compulsory. After analysis it appeared that one layer is to be permanently abandoned for optimizing the production profile. The zone is shut-off squeezing gel[3-7], cement, or else. This is typically the situation of either excessive gas production in an oil producer or excessive water production in oil or gas producers. In the case of a lower zone to be abandoned, the permanent shut-off can also be achieved by means of a TTRBP. Exclusion of a sand-producing interval can be addressed in the same way with the adequate resin for consolidation, if of interest.

TT Packers and TT Retrievable Bridge Plugs for conformance problems.

Application and typical cases for TT Packers:

- Squeeze of permanent plugging gel in lower zone (mainly water shut off).
- Pressure insulation of tubulars and equipments while treating lower zones (tubing-casing communication, low pressure rating surface equipment).
- Injectivity testing of lower interval.

Application and typical cases for TTRBP

- Squeeze of permanent plugging gel in upper zone (mainly gas shut off).
- Evaluation of upper interval production (and then estimation of the impact of permanently shutting-off of lower zone).
- Injectivity test of upper interval.

Operation of TT Packer.

The choice and preparation of the tool will depend mainly on the treatment parameters (squeeze and draw-down pressures and fluids), completion sizes and specific situations such as contingencies or well deviation.

Generally, a CT TT Packer selective treatment will included the following steps:

- RIH tool.
- Depth correlation
- Tool setting (inflation / anchoring)

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- Treatment
- Equalization of pressures across packer,
- Deflation
- Eventual flow back in case of an acid squeeze
- Pull Out tool.

Setting is done by pumping a 1/2" ball out of the CT Reel and left to gravitate in the CT. The TT-Packer is inflated and tested in place, then the bottom of the mandrel is opened to flow by activating shearing pre-set pins.

The depth correlation is necessary in most of the cases where precise setting of tool is required, for example in between two close sets of perforation. Since selective treatment concerns layers, the target window for the setting depth of the toll is often referred to perforation depth. Accuracy is usually achieved by correlation with the nipples in the production tubing using a Tubing Nipple Locator (TNL), every time that it is possible, the TNL is included in the TT Packer Bottom Hole Assembly (BHA). The TNL is ran below the nipples and then pulled out, an over-pull indication seen on the CT's weight indicator will locate the nipple. The depth of the nipple being known from CCL logs or well schematics, the distance from the nipple to the target depth is calculated. The Coiled Tubing operator then just need to run the same distance from the point where the over-pull was seen to be at setting depth. The closest the nipple from the setting depth, the better the precision. To fix ideas, in the case of Hassi-Messaoud where the pay zone is located at around 3400 m and nipples at 3200 m, the maximum accuracy is realistically 1.5 to 1 m.

Rig-up Procedure for TT Packer

A standard tool assembly would include the following devices:

- CT connector
- Double Flapper Check Valve
- Emergency disconnect sub-assembly
- Emergency circulation sub-assembly
- TNL
- Inflatable packer (with control valves)

The total tool length is averaging 5 m so is able to fit in risers between the CT BOP and the CT injector avoiding pressure deployment of the tool.

The rig-up procedure is straightforward: Connect sufficient riser length below the injector head stripper, RIH coiled tubing to have the CT connector below the end of the risers, connect the tool BHA at the end of the Coiled Tubing, Pick-up in order to stuff all the BHA in the risers, connect the risers to the top of the BOP on the well-head. The increased height due to the risers makes it safer to use a mast type coiled tubing unit.

Operation of TT-RBP.

Generally, a CT TT RBP selective treatment will be done in two stages:

- RBP setting followed by the eventual treatment:
- RIH tool.
- Depth correlation
- Tool setting (inflation / anchoring)
- Disconnection from the TT-RBP
- Treatment of the layer above RBP.
- Pull out of hole
- RBP retrieval:
- Run in hole with retrieving tool (hydraulic release overshot type)
- Equalization of pressures across RBP,
- Deflation
- Pull Out tool.

Setting is done by pumping a 1/2" ball out of the CT Reel and left to gravitate in the CT. The TTRBP is inflated and tested in place, then released from Coiled Tubing by activating a Hydraulic Disconnecting Tool. A small volume of sand is spotted to protect the fishing neck if the tool is intended to stay in place for a longer time.

Rig-up Procedure for TT-RBP

A standard tool assembly would include the following devices:

- CT connector
- Double Flapper Check Valve
- Emergency disconnect sub-assembly
- Emergency circulation sub-assembly
- TNL
- RBP running Tool
- TT RBP (with control valves)

The total tool length is averaging 5 m so is able to fit in risers between the CT BOP and the CT injector avoiding pressure deployment of the tool. The rig-up procedure is basically the same as for the TT Packer.

Ratings, Sizes and Limitations:

Both TT-RBP and TT-Packer are suited for common oilfield operations. The rubber element now accepts temperature as high as 140°C (280°F), the operation in gas well is permitted since the polymer resists better to gas impregnation. Corrosive fluids can be pumped through the tool using conventional corrosion inhibitors.

The element itself must be carefully chosen if there is a chance of setting the tool across perforation, standard element might burst, a special set-across-perforation element must be installed then.

The main limiting feature is the "maximum differential pressure". As opposed to mechanical packers, when talking about inflatable tool, the differential pressure does not represent the difference between the pressure below the tool and the pressure above the tool. For inflatable tools the differential pressure represents the delta P across the bladder of the element in any direction i.e. ($P_{inside} - P_{above}$) and ($P_{inside} - P_{below}$).

Therefore the design of any CT treatment using inflatable tools starts with the estimation of the maximum squeeze and

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draw down pressure that will be encountered during the operation. In such, computer programs that forecast pressure evolution are extremely valuable. Note that the engineer prior to the operation sets the value of P_{inside} in the tool by increasing values of shear pins.

The maximum delta P allowed (tool rating) depends in turn on the ratio of expansion (OD tool/ ID at setting). Close coordination between the tool company and the pumping company is compulsory.

Table 1 describes the pressure rating as a function of element OD and setting OD.

Tool sizes range from 1.69 to 3.375 inch so they offer application for treatment in 2 7/8 to 10 ¾ tubulars.

As a conclusion for the rating of the tools, the differential pressure available is sufficient for most of the treatments done through Coiled Tubing.

Time-wise, setting an inflatable packer takes about one hour, the rig-up is longer than on regular operation and the running speed of the CT has to be limited to about 20 m/min. This apparent longer time is actually compensated by the fact that the use of a packer for a squeeze avoids the need to fill up the annulus CT/tubing (one hour) and therefore avoids the need to evacuate this fluid as well. Nitrogen is saved there. The packer being relatively short, the pressure drop that it creates is not significant and no reduction in pumping rates is required.

If required low back of treating fluids can be done with the packer still on the CT, circulating the nitrogen through the circulation valve above the tool (no need to pull out prior to kick-off). The packer needs however to be ran below the perforations to avoid adverse effect of flow on the deflated element.

Inherent to the fact that these tools are ”all-zone-below” or “all-zones-above” pinpoint selectivity is not achieved leading ultimately to the need of Through Tubing Straddle Packers.

Straddle Packers

Coiled Tubing conveyed Straddle Packers (see Fig. 1) achieves isolation both from top and bottom of a layer. They enable to treat middle intervals eliminating the need of a sand plug with a conventional TT packer or the conjunction of a TTRBP and a TT Packer. They are multi-settable, the fluid being pumped through being used to create the back pressure that inflates the elements. The reliability of these tools have progressed tremendously for instance up to 11 settings have been performed during the stimulation of a gas well in the Rhourde Nousse field. The top packer is sometimes used alone as a multi-set packer.

Description of Operation and Deployment

The operation of the tool is controlled using three balls. The first ball (0.5” diameter) is circulated to the tool through the coiled tubing to initiate the setting operation, once the tool is at the required depth. The next largest ball (0.63” diameter) is used to open circulation port above the tool once the treatment operation is completed. This allows a circulation path through the coiled while pulling out of the hole. The largest ball (0.75” diameter) is used in case the straddle packer has to be disconnected from the coiled tubing in an emergency situation.

The deployment procedure starts with building up coiled tubing connector to its end. The next sequence of events is as follows: pull test connector against coiled tubing injector and pack-off to 10,000 lbs. Circulate largest ball (0.75” diameter) through the coiled tubing to ensure the tubing is free of obstruction. Once the ball is at the end of coiled tubing, pressure test the connector to 5000 psi.

Assemble Slick line lubricator and hang vertically from the crane. Install coiled tubing BOP (blow out preventor) on the wellhead. Run Slick out through the bottom of the lubricator. Screw Slick-line connection to the top of packer (using cross-over). Screw fishing neck into the top of the Swivel Sub. Attach to Slick-line pulling tool. Make up tools from top to bottom as listed below:

- Swivel Sub
- Coiled tubing deployment bar
- Back pressure valve
- Bleed Sub
- Emergency disconnect
- Tubing nipple locator
- Injection control valve
- Spotting valve
- Upper section packer
- Spacer as required
- Treatment valve
- Lower packer section

Next, pull tool string into wireline lubricator and make up to coiled tubing BOP. Pressures test the lubricator to a minimum of wellhead pressure. Open the well and run the tool into well until the coiled tubing deployment bar is situated across the pipe rams. Close the pipe/slip rams on coiled tubing deployment bar. Bleed off pressure above the pipe/slip rams. Lay down the lubricator and slick-line. Bring coiled tubing injector head to BOP. Open pipe/slip rams and run the tool 30 m to make sure tool does not hang up any wellhead shoulders. Run the tool at speed not greater than 100 ft/min. Perform periodically a weight check, recording all parameter for future reference. Record depth indications given by the nipple locator (working with seeing over pulls on weight indicator). It may require repeating the location sequence additional times if the tubing nipple locator gives slight indications. Correlate the depth with CCL-gamma ray log.

Finally, position the packer in the blank pipe to perform blank test (preferred at bottom perforations).

Inflation

The first setting of the packer is usually the blank test (see Figs. 3 to 8). For this, insert the 0.50” diameter setting ball

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into the reel. Circulate the ball with pumping treated water at rate of 1 to 1.5 BPM until the ball will pass over the gooseneck, then stop pumping and wait to the ball to fall down by gravity and seat on the ICV (injection control valve).

Once the ball seats, pressure in CT should increase. Indication should be seen on the recording display panel. Apply pressure (500 psi) above the ICV calculated pressure. The ICV pressure must be calculated prior the operation, based on the density of the fluid and bottom hole pressure. While circulating at 0.3 BPM, slack off 1000 lbs on the tool to check that the elements are inflated.

After successful weight check of the tool to confirm proper element inflation, continue pumping at same rate and apply tension to coiled tubing to close spotting valve bypass. It takes 3000 lbs over weight to close spotting valve. As tension is applied, a rapid increase in coiled tubing pressure will be seen at surface. Increase the coiled tubing pressure to the desired pressure while maintaining coiled tubing tension to keep spotting valve closed during the blank test

Equalization and deflation

Slack off on the tool. A rapid drop tubing pressure indicates spotting valve bypass has been opened. Slack off coiled tubing to neutral. Tubing pressure will drop only to ICV closing pressure. Do not slack any more weight on the tool. Bleed off coiled tubing pressure. Few minutes must be allowed to equalize pressure. Element will deflate and the tool can be deployed to new setting.

Treatments with gels using Coiled tubing and inflatables

In the cases where a particular layer is to be shut-off by means of squeezing a treating fluid (such as cross-linked gels or cement) a great attention should be given to the correct placement of the fluids, especially when fluids setting is time controlled. As we have seen, the various inflatables tools allow to place the treatment fluid in the target layer with great accuracy. A compulsory condition however is -first to have a proper isolation of the layers in the formation -second in the case of cemented liner to ensure that there is no communication behind casing. Gamma ray and cement bond log give reliable information for this. But that is not sufficient. The design must also take into account what is going to happen to the fluid once in the right place and before it sets. For operational reasons the setting time of the fluid is adjusted to provide a safe time margin (by adding delay agents). In this time window between the moment the fluid is in place and the moment it sets the down hole hydraulics must be carefully controlled. We must prevent any over-displacement of the treating fluid away from the near well bore area where it is the most efficient. To achieve this, the hydrostatic pressure of the displacement fluid must be less than reservoir pressure or held back by means of a back pressure valve. Also, in the case of packers and straddles, the tool is often deflated before setting time, this is to avoid that the fluid once set refrains the deflation of the tool and therefore its retrieval. Therefore once the element is deflated the treatment fluid is exposed to the fluids in the annulus coiled tubing / production tubing, again this hydrostatic pressure has to be considered. Attention should be given to possible cross flow. In general, if at all possible, under-displacement is recommended.

Likewise, we must avoid formation pressure to expel the treatment fluid back out of the matrix. This is likely to happen while treating gas wells where the large volume of well-bore gas is decompressed compared to the reservoir.

Finally, close control of the job execution parameters such as rate, pressures is crucial to the success of the operation. Real-time bottom hole pressure (BHP) computation (or measurement) is important to avoid exceeding fracture pressure and to be able to react quickly in the case of a problem. When squeezing with a packer, the operator is somewhat blind because the pressure response of the formation can only be seen through the surface pumping pressure which depends on rate. Real time BHP computation from surface pumping pressure and friction pressure estimation are recommended to control the operation.

Conformance Problems: Field case studies

Gassi Touil Oil well A – Gas shut-Off-Case Study 1

Summary

A Through Tubing Inflatable Packer was used to squeeze polymer gel to shut-off a gas producing interval in oil producing Well A of the Gassi-Touil field, Algeria. A sand plug was used to isolate the lower intervals while the gas shut-off was performed on the upper interval. A communication between the production tubing and first annulus was isolated by the use of a TT inflatable packer.

Objectives

Well A was producing excessive gas with the oil. The objective of the Well Intervention Operation was as follows:
Set a sand plug in the 7" liner to protect the lower intervals,
Install the TT Packer in the completion tubing of the well.
Perform an injectivity test on the upper (gas producing) interval, followed with the injection of polymer gel.

Background

Well A is completed as a Single String Producer with a 3 1/2" production tubing string and a 7" liner. There were four sets of perforations. The upper set was producing 100% gas, zone 2 was producing ~60m3/d oil, zones 3 and 4 were watered out and not producing.

The objective of the operation was to shut-off the gas producing interval and return the well to production from zone 2, the oil producing interval.

Design

Due to the size of the minimum restriction in the Production Tubing String a 2 1/8" Inflatable Tool String was recommended.

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The following Operations Sequence was proposed after the perforation operation and slickline control run had been performed:

Perform a Control and Tubing/ Well bore Cleanup Run. This operation was to clean up the inside surface of the completion tubing where the TT Packer was to be set.

Perform a "Dummy" Packer run. A 2 1/8" Dummy Packer BHA with the same lengths and OD's as the actual BHA was RIH to verify that the actual BHA could be safely deployed into place

Placement of sand plug. This sand plug was set in the liner to protect the lower three intervals from the polymer gel treatment.

Packer Installation. RIH 2 1/8" TT Packer and set in the completion tubing.

Perform an Injectivity Test on the upper zone. Pump polymer gel fluid into the upper zone to shut-off the gas. Wait 48 hours for the gel to completely sure. Repeat injectivity test and pump inorganic gel (Aqueous silicate) as required to permanently seal off the interval.

Clean out polymer gel residue by high pressure jetting and return the well to production.

Execution

The operation on Well A was successfully performed as per the design. Additional inorganic fluid was pumped after the polymer gel treatment. The following BHA was used on Well A:

- CT connector
- Back pressure valve
- Hydraulic disconnect
- Inflation valve
- Tubing nipple locator
- Hydraulic running tool
- TT Packer

Evaluation

The Through Tubing Inflatables used on the intervention on well A worked successfully. The TT Packer was properly installed in the tubing and the polymer gel squeeze was completed successfully.

After the treatment a production test was performed on Well A. The gas production from the upper interval has been completely shut-off and the well is reported to be producing 63m3/d since the operation. This job was an excellent success to demonstrate the synergy between CT and through tubing inflatables solutions.

Rhourde Nouss well B - Case Study 2

Summary

Through Tubing Inflatables and Polymer gel were used to Shut-Off water production from Gas and Condensate Producer Well B in Rhourde Adra, Algeria. The water production reduced from pre-treatment rates greater than 421 m^3/day to post-treatment rates of 5 m^3/day.

Objectives

Gas and Condensate producer Well B was producing water. The objective of the job was twofold:

To identify the water producing interval and,

To shut-off water production by placement of Polymer gel using CT deployed Through Tubing Inflatable Tools. These Inflatable tools were run through the 4 ½" Tubing String and set in the 7" Liner.

Background

Well B is completed as a Single String Producer with a 4 ½" production tubing string in a 7" cemented liner.

8 perforation intervals exist in the liner out of which 4 were producing gas and condensate. The top zone and the bottom three zones were not producing at all, and the fifth interval was determined to be responsible for > 92% of produced water as well as > 65% of gas.

Prior to the Water Shut-Off operation, the well was shut-in due to difficulties in handling the water produced (large volumes and high salinity). A joint analysis done by a joint Coiled Tubing and Wireline team highlighted the potential risk of losing the > 65% gas production from the fifth zone after the shut off treatment.

Design

Due to the size of the minimum restriction in the Production Tubing String (3.313" ID "X" Nipple), a 3" Inflatable Tool String was recommended.

Extensive fluid testing was performed in the Hassi-Messaoud laboratory to determine the ideal Water Shutoff Fluid and Injectivity Improvement Acid formulations using bottom hole data, produced fluids from the well.

The Operations Sequence proposed was as follows:

Perform a Control/ Tubing Clean-Up Run. This run was also used to correlate the CT depths with the Log depths.

Perform a "Dummy" Packer run. A 3" Dummy Packer Bottom Hole Assembly (BHA) with the same lengths and OD's as the actual BHA was run in hole (RIH) to verify that the actual BHA could be safely deployed into place.

RIH and install a 3" TTRBP below the zone suspected to produce water (Zone 5) Test the well (open the well to produce and monitor surface fluid for water). Confirm that the Zone 5 is the water producing interval.

RIH and install a 3" Packer between Zones 4 and 5 - in effect "straddling off" Zone 5 and isolating it for treatment.

Perform an injectivity test using water treated with a clay stabilizer and a linear gel with similar rheology to the polymer gel formulation. The results of this injectivity test were to be used to select the Water Shut-Off Treatment Fluid. The options were polyacrylamide gel (in case of high injectivity > 1.0 bpm at maximum allowable surface pressure (MASP), or inorganic gel (in the case of low injectivity < 0.8 bpm at MASP).

Pump acid and repeat injectivity test as required. Inject polymer gel treatment. Allow 48 hours for polymer gel to

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cure. Unseat Packer and POOH. RIH and clean-out residue in well bore. Put well on production and test for water flow.
RIH and unseat TTRBP.
End operation.

Execution

The operation was executed according to the design. One incident was reported.

The following equipment was used

- 1 ¾", HS 80 CM, 0.134" Coiled Tubing
- Bottom Hole Assembly:
- Coiled Tubing Connector
- Dual Flapper Check Valve
- Hydraulic Emergency Disconnect
- Tubing Nipple Locator
- RBP Inflation Valve/ Running Tool
- 3" TTRBP
- Double Blow Out Preventers and Double Strippers

The 1st TTRBP that was run in the well did not set. It was POOH to surface and inspected. The setting ball was found on the seat. Failure to set the TTRBP was attributed to insufficient pump rate applied to the ball.

A 2nd TTRBP was RIH and set successfully. The pressures recorded by the Coiled Tubing sensors during the setting procedure are presented in Fig. 2 The running tool was then released and the CT POOH. The Injection packer BHA was then picked up and RIH. The Packer was installed successfully. An injectivity test was performed using treated water.

The results from the injectivity test indicated a tight formation and it was then decided to perform an acid stimulation. Injectivity improved from 0.50 bpm to 1.65 bpm at 2550 psi after treatment with HF Acid. A total of 3 m^3 of polymer gel were thereafter injected into the perforations at 1.17 bpm, 2600 psi. After the polymer gel was completely placed, the packer was unset and retrieved with 5500 lbs. overpull (3600 lbs. to open the equalize valve).

The well was then shut-in for 48 hours.

Evaluation

The Injectivity Improvement Acid Treatment was successful. Injection Rates increased from 0.5 bpm to 1.65 bpm - a 330% increase in injectivity.

As a result of this improved injectivity, polymer gel was selected as the preferred Water Shut-Off Treatment Fluid. After the 48 hour waiting-on-ringing time, the well was opened up, cleaned out and returned to production. A Production Logging Tool (PLT) was then run across the treated intervals for comparison with the pre-treatment PLT logs that had been run.

The interpretation on the original production logs showed water production at 421 m^3/d at a surface production rate of 796 Msm^3/d of gas at the highest test rate. At the time it was recognized that approximately 60% of the gas production came from the lower zone. After the shutoff water production dropped to 5 m^3/d. These results are shown in Table 2.

Haoud Berkaoui Well C - Case Study 3

Summary

A Through Tubing Inflatable RBP was used to temporarily isolate a suspected water production zone in well Well C in Haoud Berkaoui, Algeria. The TTRBP was left in place while a production flow test was performed on the upper interval.

Objectives

Well C was producing water. The objective of the Well Intervention Operation on well C was as follows:

Install the TTRBP in the blank-pipe section of the Slotted Liner.

Perform a Production Flow Test on the section above the blank pipe.

Background

Well C is completed as a Single String Producer with a 4 ½" production tubing string and a 4 1/2" slotted liner. The two perforation intervals existing in the slotted liner were producing water.

The objective of the production test was to flow the upper zone for a period of time and evaluate the produced fluids. A PLT performed on this well showed a cross flow of 20 cum/day of water from the lower reservoir (SI) to the upper one (T1+T2). Therefore the RBP was to remain in place for a few days (or weeks) to provide the required time for the water to be produced and to allow a better flow test of the upper formation (T1+T2).

Since there was no cement behind the liner, and it was known that cross-flow of fluids had occurred between the lower and the upper intervals, it was expected that the upper interval in Well C would produce some water.

Depending on the fluid production from this upper interval, the decision to either bring the interval on-line for production or leave the TTRBP permanently to abandon the zone would be made. The TTRBP will be retrieved if the flow test shows to be negative, otherwise a cement plug will be pumped on top of the TTRBP.

Design

Due to the size of the minimum restriction in the Production Tubing String (3.228" ID Nipple), a 2 1/8" Inflatable Tool String was recommended.

The following Operations Sequence was proposed after the perforation operation and slickline control run had been performed:

Perform a Control and Tubing/ Wellbore Cleanup Run. This operation was to clean up the perforations and the inside surface of the cemented liner where the TTRBP will be set.

Perform a "Dummy" Packer run. A 2 1/8" Dummy Packer BHA with the same lengths and OD's as the actual BHA was

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RIH to verify that the actual BHA could be safely deployed into place

RBP Installation. RIH 2 1/8" TTRBP between the two sets of perforations.

Perform a Production Test on the upper zone. This production flow is expected to be quite prolonged due to the extensive amount of cross-flow known to have been fed from the lower to the upper interval.

Execution

The operation on Well C was successfully performed. The following BHA was used on Well C:

- CT connector
- Back pressure valve
- Hydraulic disconnect
- Inflation valve
- Tubing nipple locator
- Hydraulic running tool
- RBP

Evaluation

The Through Tubing Inflatables used on the intervention on Well C worked successfully. The TTRBP was properly installed between the two perforation intervals, the production test was completed successfully..

Guellala well D - Case Study 4

Summary

A Through Tubing Inflatable Retrievable Bridge Plug (RBP) was used to temporarily abandon a water production zone in Well C in Guellala, Algeria. The TTRBP was left in place while a production flow test was performed on the upper interval.

Objectives

Well C was producing water. The objective of this well intervention operation was threefold:

Perforate the SI reservoir across the zone from 3551.5m - 3554m,

Install via CT, a TTRBP between the new (3551.5m - 3554m) and the old (3568.5m - 3580m) perforations,

Perform a Production Flow Test on the new perforation interval in the SI reservoir.

Background

Well D is completed as a Single String Producer with a 4 ½" production tubing string and a 4 1/2" cemented liner. The perforation interval in the liner was producing water.

It was expected that the newly perforated upper interval in Well D would produce some water. However, as the fluid type and deliverability of the upper SI was not certain, the interval was to be opened to flow for a few days for testing.

Design

Due to the size of the minimum restriction in the Production Tubing String (3.228" ID Nipple), a 2 1/8" Inflatable Tool String was recommended.

The following Operations Sequence was proposed after the perforation operation and slickline control run had been performed:

Perform a Control and Tubing/ Wellbore Cleanup Run. This operation was to clean up the perforations and the inside surface of the cemented liner where the RBP will be set.

Perform a "Dummy" Packer run. A 2 1/8" Dummy Packer BHA with the same lengths and OD's as the actual BHA was RIH to verify that the actual BHA could be safely deployed into place

TTRBP Installation. RIH 2 1/8" TTRBP above water producing interval and below the newly perforated interval. The spacing between these two sets of perforations was 14.5m (3554m- 3568.5m)

Perform a Production Test on the SI reservoir (upper zone).

RIH CT to retrieve the RBP.

Execution

The operation on Well D was successfully performed. A few difficulties were encountered while attempting to locate the production nipple. The following BHA was used for the Cleanup and Correlate Run on Well D:

- CT connector
- Hydraulic disconnect
- Tubing Nipple Locator
- Jetting nozzle

After the depths were correlated the RBP was then RIH and successfully installed at the designed depth. Fig 3 shows the pressure recordings of the RBP setting procedure.

After setting the RBP, the CT was POOH and the well handed for production testing of the upper interval. This interval of the well was then kicked off using Nitrogen. However, only water was produced.

The Kick-Off was continued for a total period of 3 days during which only water was produced from the upper interval. The water produced was saturated with salt and no traces of oil were found. At the end of the 4th day the well kept producing water, therefore the decision to retrieve the RBP was taken. The fishing BHA was then made up and RIH.

- CT connector
- Back pressure valve
- Hydraulic disconnect
- Wash over retrieving head

The RBP was successfully retrieved and POOH to surface.

Evaluation

The Through Tubing Inflatables used on the intervention on Well D worked successfully. The RBP was installed in place, the production test completed successfully, and the RBP eventually retrieved after the test.

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Conclusions

1. Inflatable element technology available today provides reliable high-performance element. These elements present a 5000 psi differential pressure rating at a 2:1 expansion and 2000 psi at 3:1 expansion at temperatures in excess of 300°F. This allows the use of these elements in wells that are more hostile than previously possible while increasing job reliability for less demanding applications.
2. The zonal isolation offered by inflatable tools combined with the capabilities of the Coiled Tubing offers the possibility to selectively production test layers. This technique offers a simple mean to better understand conformance problem in a well.
3. This technique allows to evaluate the impact of a permanent plugging treatment before pumping the job in the case of a lower zone shut-off.
4. CT conveyed TT-Packers are quick and reliable ways to selectively treat all zones located below the tool and TT-RBP to treat selectively all the zones above. Straddle inflatable packers require a more complex set-up but allow to focus on middle intervals and offer multiple settings.
5. Polymeric and inorganic gels have been accurately placed with CT conveyed inflatable tools in Algeria and led to successful solving of conformance problems.
6. Close control over the pumping parameters, downhole hydraulics and setting time of the gels are key to the success of the operation.
7. Currently, no system is available to selectively production test lower zones or individual intermediate zones. This area should be developed.

Nomenclature

bbl	= Barrel (42 gallons)
BHP	= Bottom Hole Pressure
BOPD	= Barrels of Oil Per Day
bbl/min	= barrels per minute
CT	= Coiled Tubing
GOR	= Gas-Oil-Ratio, SCF/STB
GSO	= Gas Shutoff
RBP	= Retrievable Bridge Plug
lbm	= Pound Mass
psi	= Pounds per Square Inch
WC	= Water Cut, %
WHP	= Wellhead Pressure
WSO	= Water Shutoff

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SI Metric Conversion Factors

bpd	x 1.840 127	E-06	= m^3s^{-1}
bpm	x 2.649 783	E-03	= m^3s^{-1}
°F	(°F-32)/1.8		= °C
ft	x 3.048*	E-01	= m
in.	x 2.54*	E-02	= m
lb.m	x 4.535 924	E-01	= kg
psi	x 6.894 757	E+00	= kPa

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Table 1: Recommended Inflatable Tool Sizes

TOOL	MAXIMUM CASING SIZE TO SET IN WITH MAXIMUM PRESSURE IN THAT SIZE								
OD	2 7/8"	3 1/2"	4"	4 1/2"	5"	5 1/2"	7"	9 5/8"	10 3/4"
1.690	5500	4600	3200	2500	1900	1600			
1.690	5500	4600	3200	2500	1900	1600			
1.690	**5500**	**4600**	**3200**	**2500**	**1900**	**1600**			
2.130	**6000**	**6000**	**5500**	**4300**	**3100**	**2400**	**1200**		
2.130	6000	6000	5500	4300	3100	2400	1200		
2.500		6500	6500	6300	4800	4000	1850	**1250**	
2.500		**6500**	**6500**	**6300**	**4800**	**4000**	**1850**	**1250**	
3.000			8000	8000	8000	7700	3700	1400	
3.000			**8000**	**8000**	**8000**	**7700**	**3700**	**1400**	
3.000			8000	8000	8000	7700	3700	1400	
3.000			8000	8000	8000	7700	3700	1400	
3.375				**8500**	**8500**	**8500**	**5250**	**2200**	**1500**
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500
3.375				8500	8500	8500	5250	2200	1500

Table 2: Well B PLT Log Data: Downhole Water Flow Rates

	Date	Downhole Rate, m^3/day
Pre Treatment	03/28/97	267.1
Post Treatment	10/30/97	83.8

This PLQL data interpretation provides a qualitative comparison of the pre and post treatment water rates. The interpretation model does not allow the presence of condensate and thus has limited application.

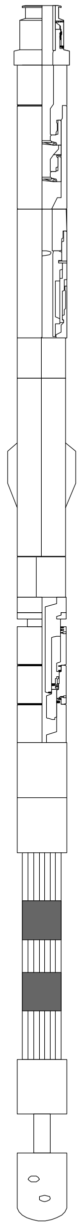
BHA RETRIEVABLE PACKER	Item	Description
	1	Coiled Tubing Connector
	2	Check Valve
	3	Emergency Disconnect
	4	Crossover
	5	Nipple Profile Locator
	6	Crossover
	9	Pull Equalise Running Tool
	9a	Retrievable Packer
		Ball Seat (1/2" Ball Size)

Fig. 1: Typical Inflatable Tool String BHA

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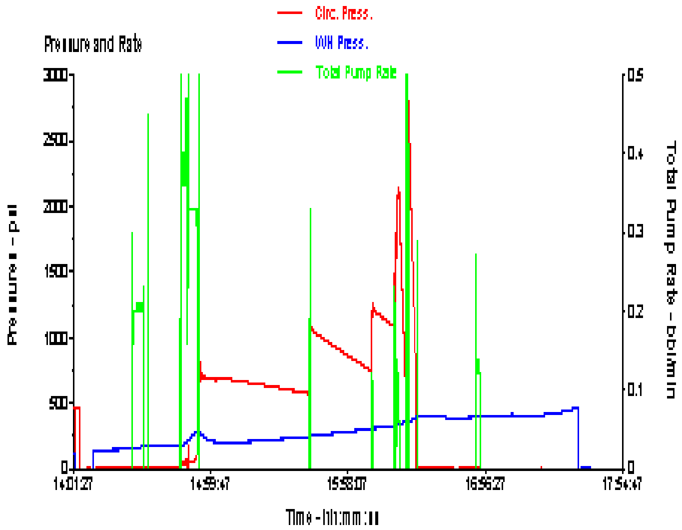

Fig. 2: RBP Setting Procedure - well B

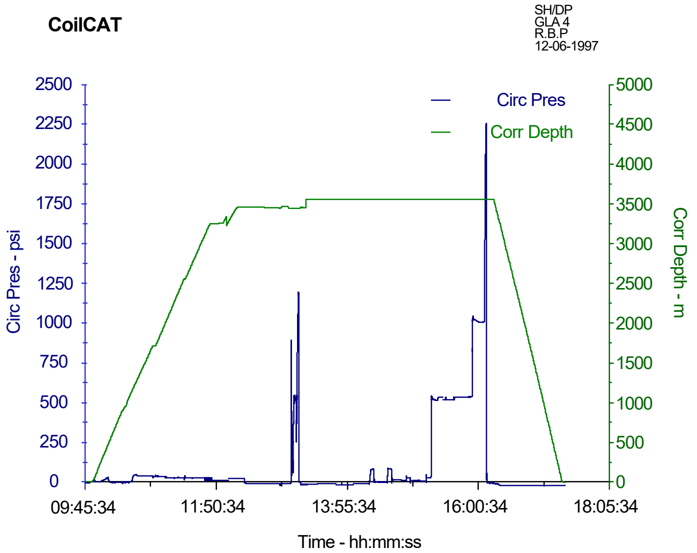

Fig. 3: RBP Setting Procedure - well D

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